Quantifying and Mitigating the Impacts of PV in Distribution Systems

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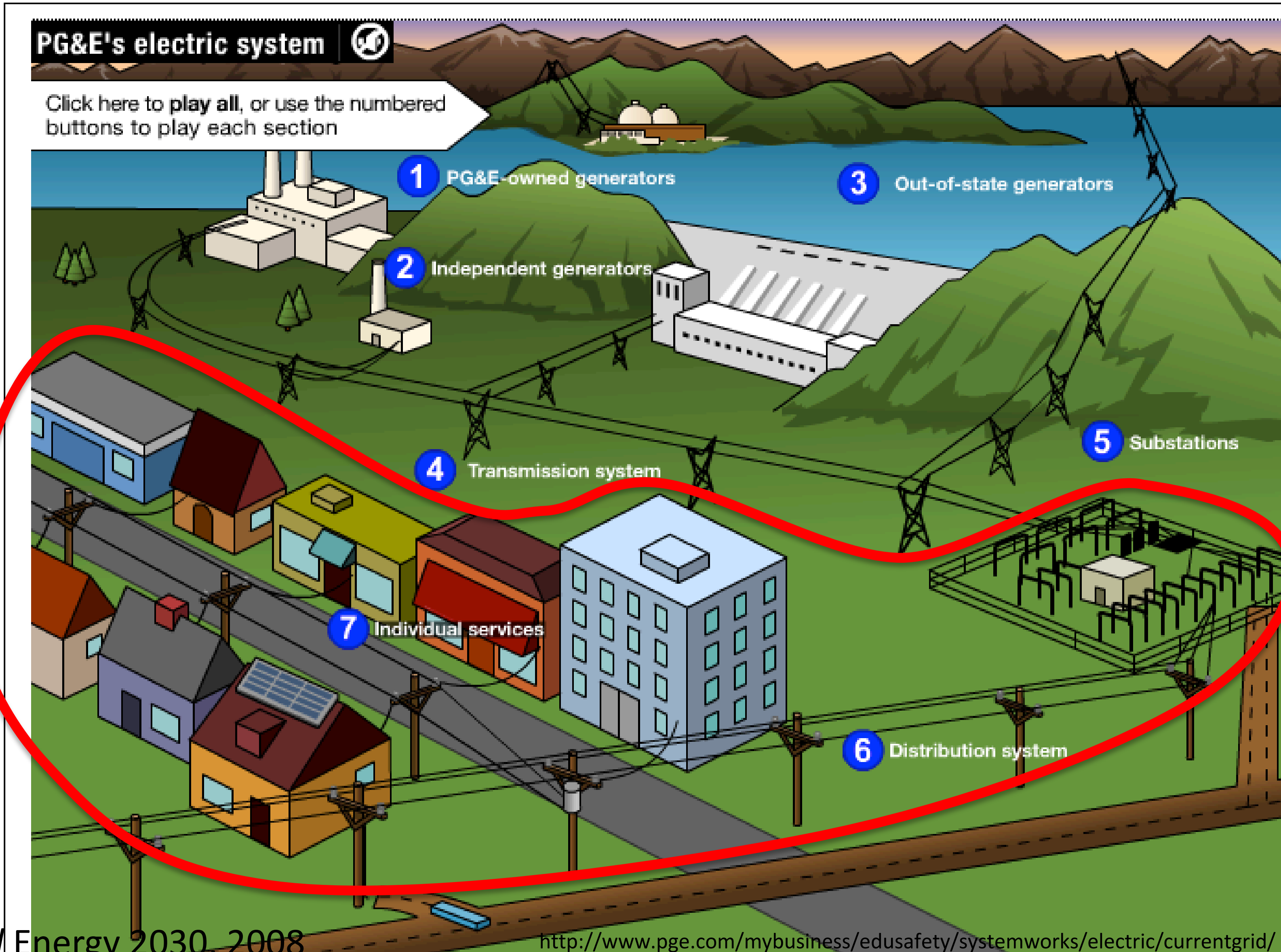
How will distributed photovoltaics (PV) impact distribution system infrastructure?



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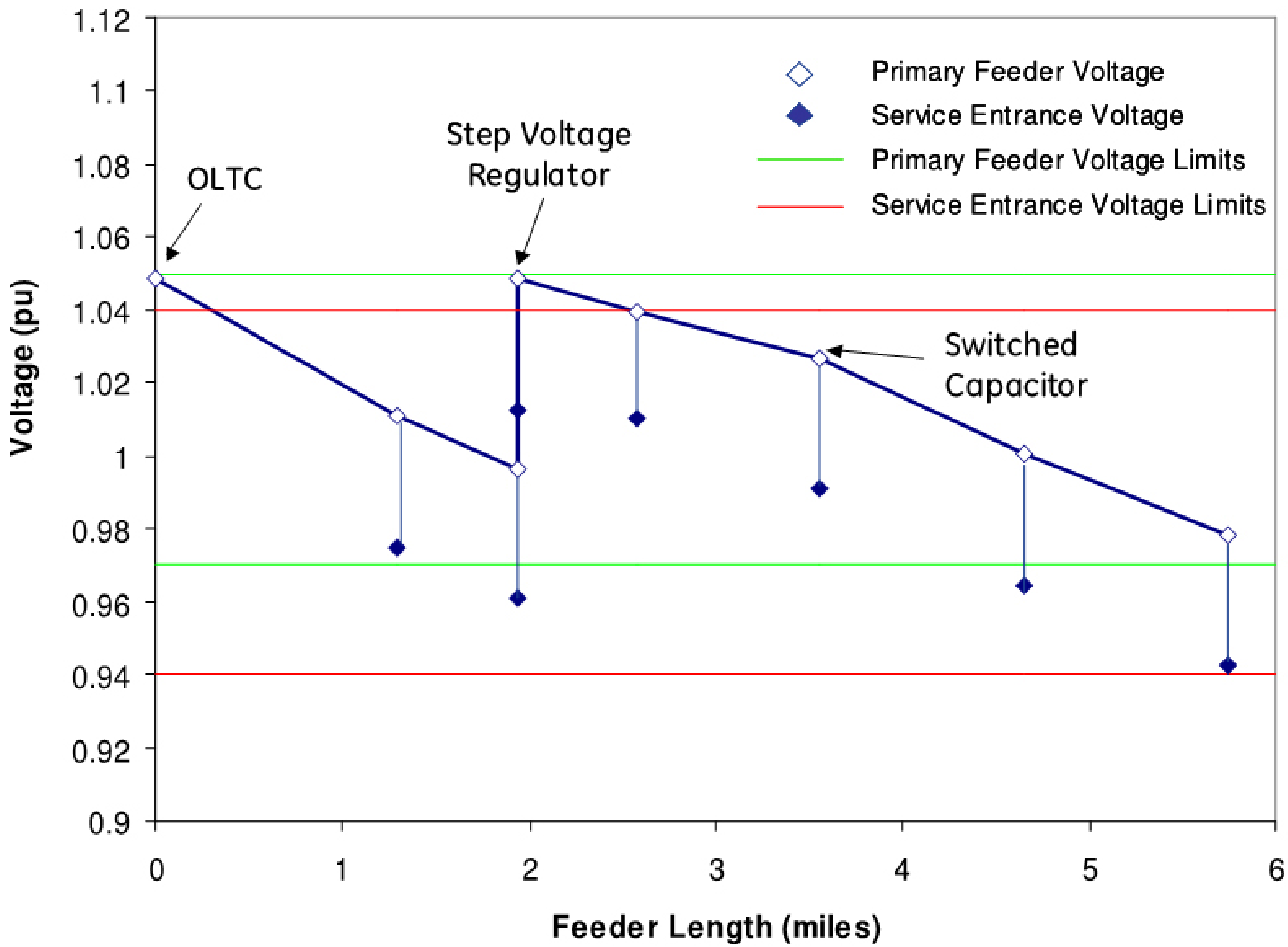

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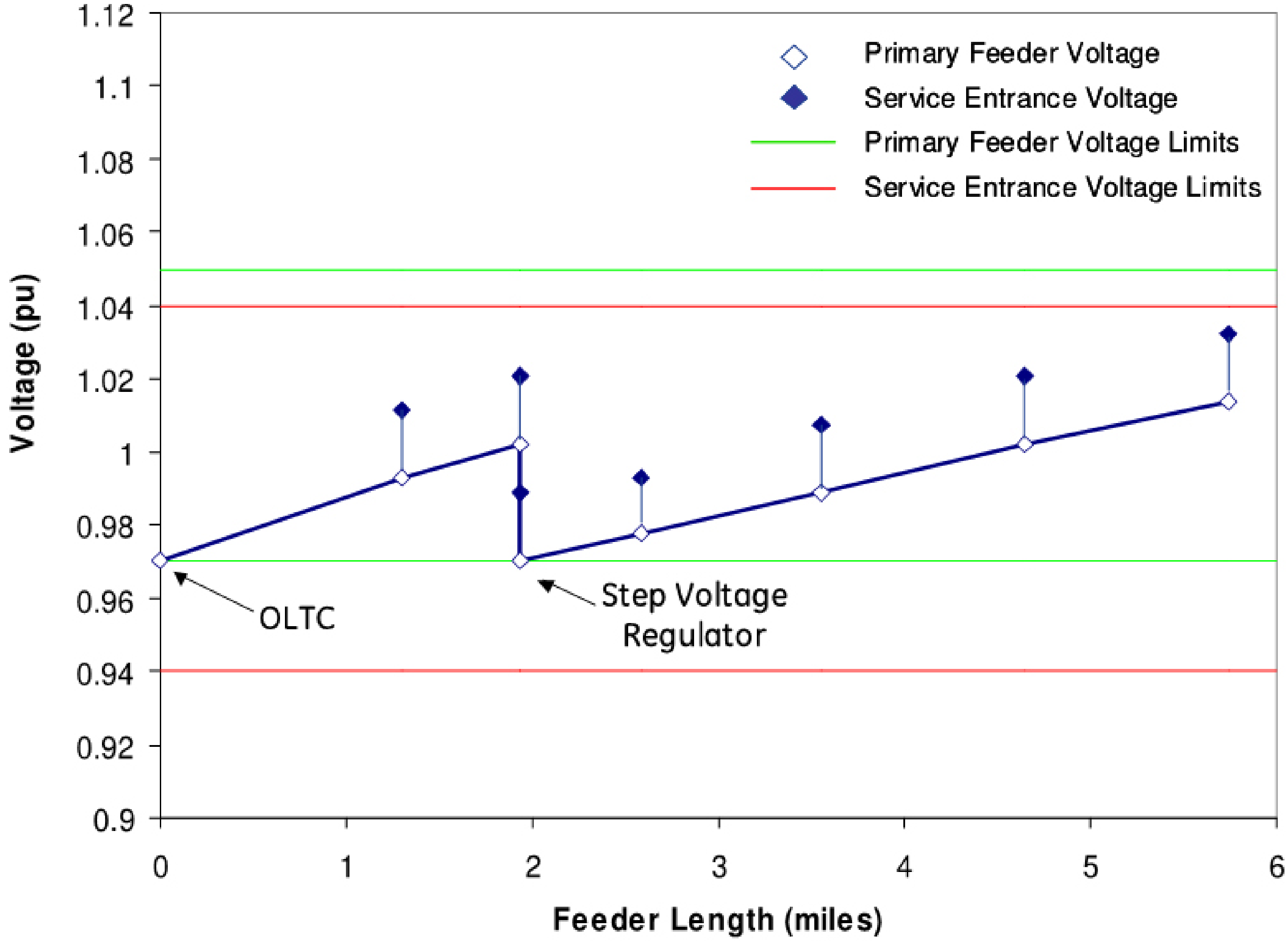

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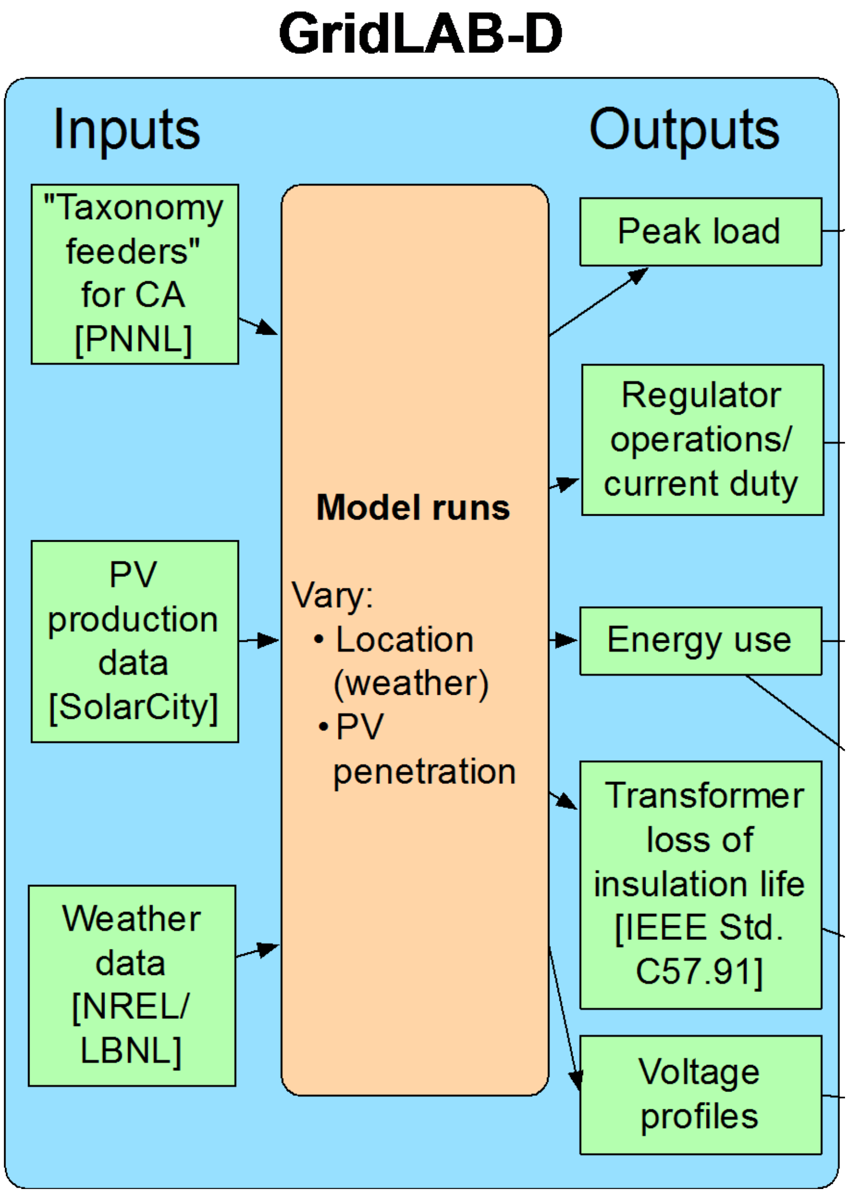
Talk Overview

1. **Simulation study**: How do distributed PV impacts vary across feeder types and climates?
   - Location has strongest influence on voltage excursions and capacity deferral benefit
   - Feeder type has strongest influence on changes in resistive losses and voltage regulator operations
2. **Economic interpretation** of results in PG&E territory
   - Avoided energy costs *much* larger than other costs
3. **A solution?** How can distributed inverters help with voltage and resistive losses?
   - Application of model-free optimal control tools for volt-VAR optimization

Part 1:
Simulation Study -- Engineering Impacts

Simulation Framework



Investigate:

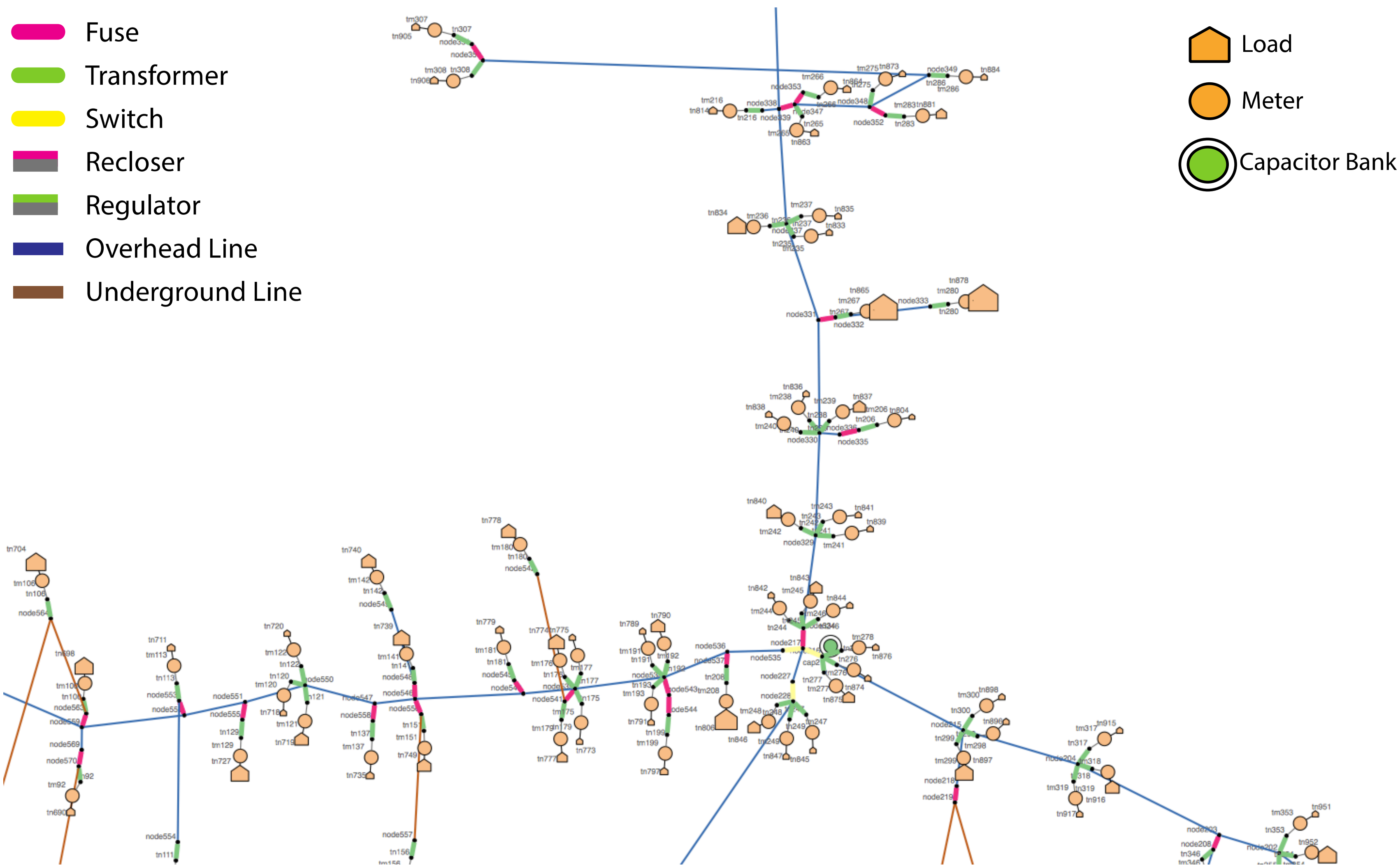
- Change in resistive losses
- Impact on peak load
- Voltage regulator operations
- Voltage magnitude excursions
- Reverse power flow
- Impact on secondary xfrmr aging
- Simulation year: Aug 2011-Aug 2012

Feeder Characteristics

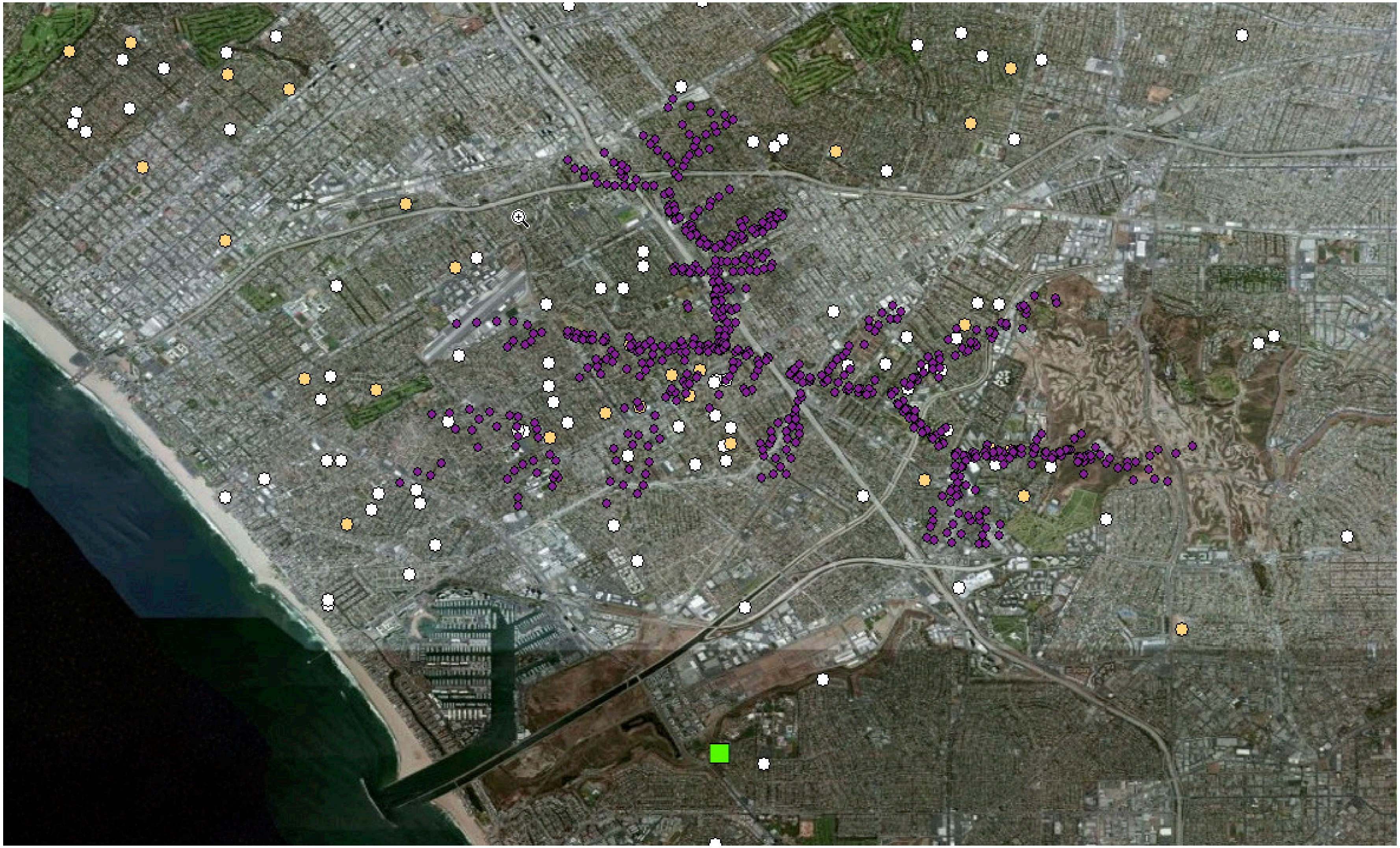
Name*	Serves [10]	Nominal Peak Load (MW) [10]	Dist. Trans-formers	Avg House (kW) [11]	Approx Length (km)	Baseline Peak Load (MW)		
						Berk.	L.A.	Sac.
R1-12.47-1	mod. suburban & rural	7.15	618	4.0	5.5	5.56	5.38	7.59
R1-12.47-2	mod. suburban & lt. rural	2.83	264	4.5	10.3	2.00	2.04	2.82
R1-12.47-3	moderate urban	1.35	22	8.0	1.9	1.27	1.25	1.60
R1-12.47-4	heavy suburban	5.30	50	4.0	2.3	4.31	4.09	5.65
R1-25.00-1	light rural	2.10	115	6.0	52.5	2.35	2.23	3.00
R3-12.47-1	heavy urban	8.40	472	12.0	4.0	6.64	6.30	8.70
R3-12.47-2	moderate urban	4.30	62	14.0	5.7	3.45	3.27	4.40
R3-12.47-3	heavy suburban	7.80	1,733	4.0†	10.4	7.54	7.00	9.67

- PNNL taxonomy feeder set
  - Total set: 23 identified from sample of 575 feeder models from U.S.
  - We chose the 8 feeders from climates present in California
- Urban, suburban, rural
- Voltage 12.5 or 25 kV
- Length from 2-50 miles
- Peak demand 1-10 MW

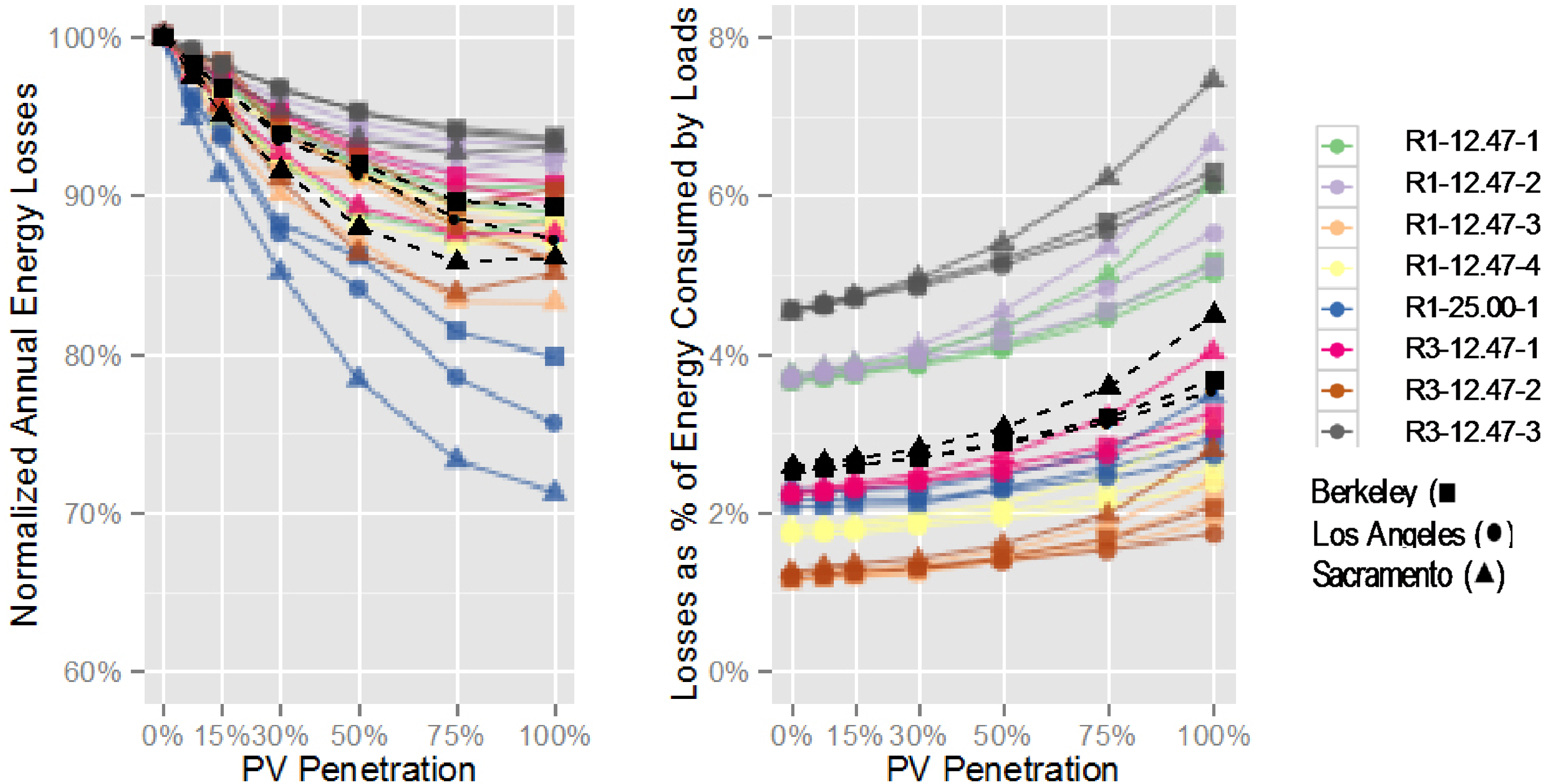
A Hypothetical Geography



PV/Meter Matching

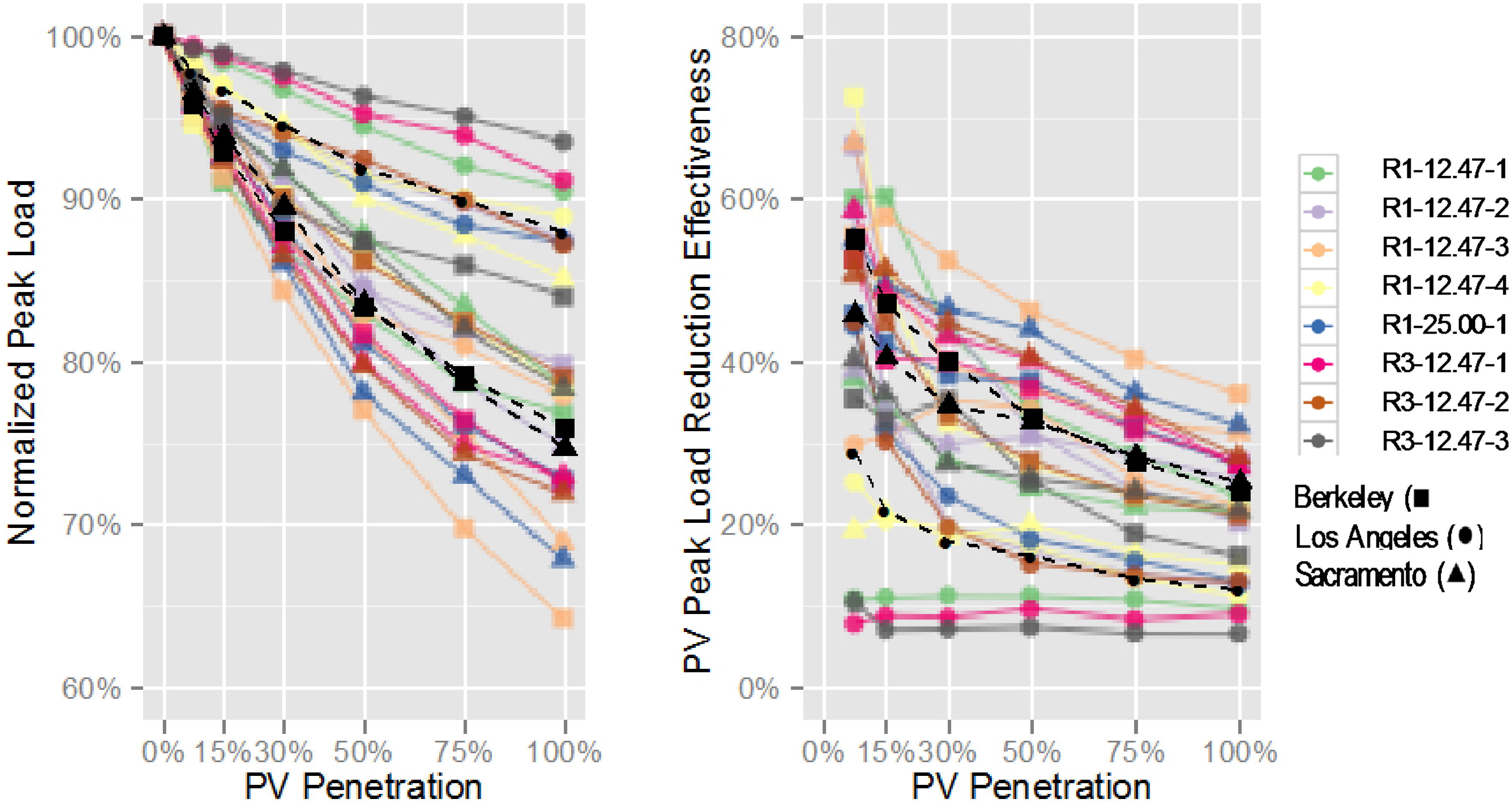


Impact on Losses



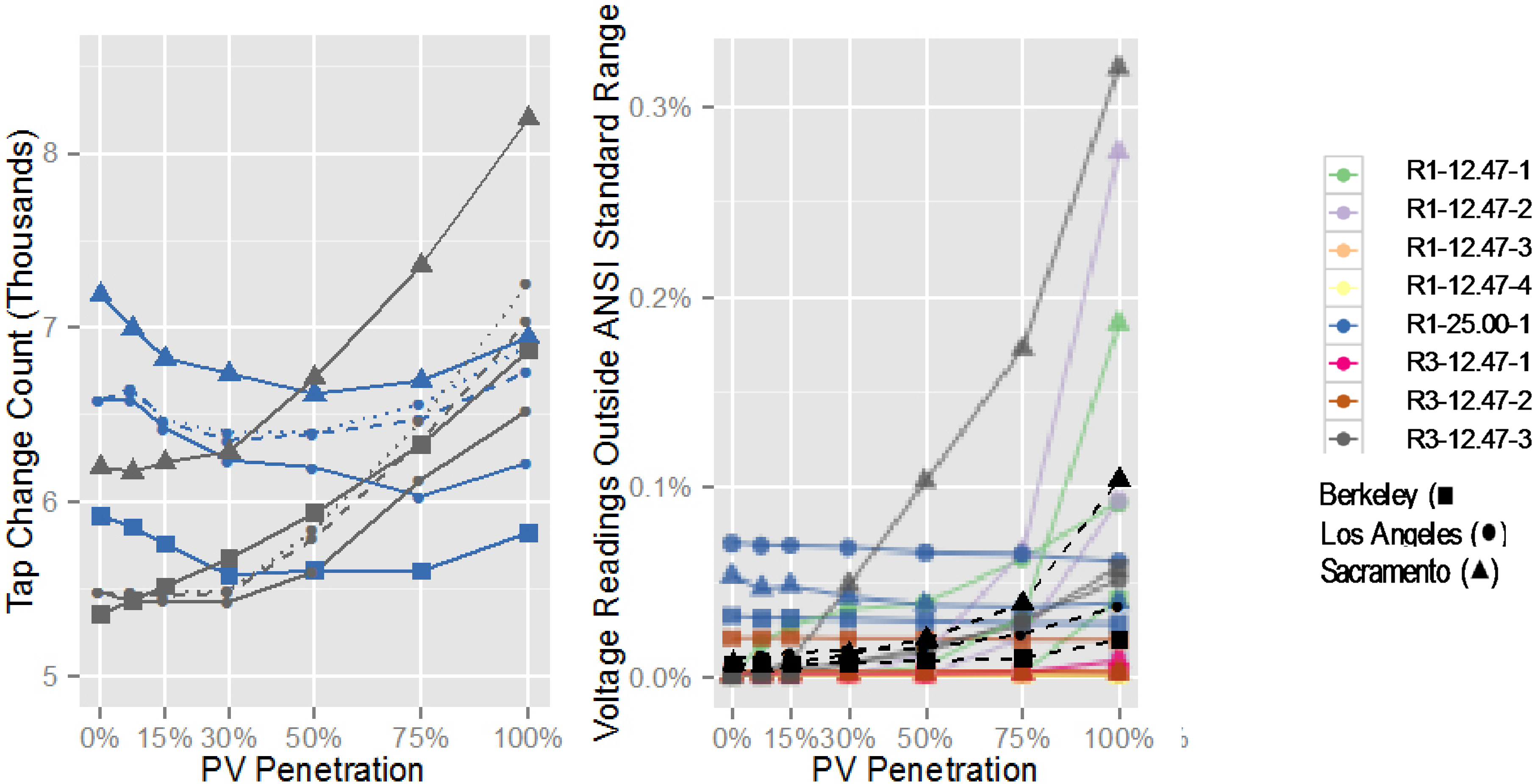
- Losses decline, but even at 100% penetration improvements are low
- Losses as a fraction of energy delivered by utility increase

Impact on Peak Load



- Peak load declines, but even at 100% penetration, decline is low

Impact on Voltage

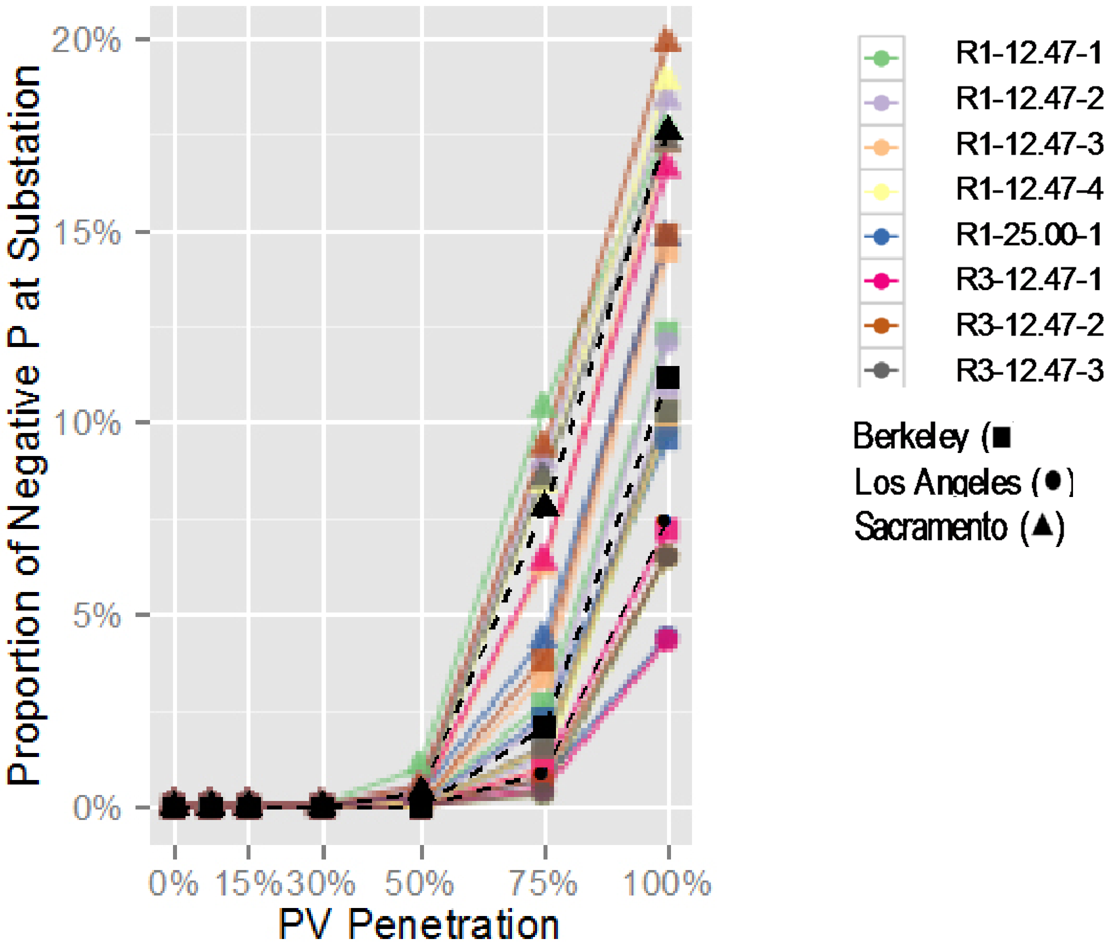


- Regulator tap counts increase on one circuit, decrease on another
- No impact on voltage excursions on most feeders, but there are exceptions

Transformer Aging and Reverse Flow

Secondary distribution transformer aging

- In all but one case, change in aging negligible
- Results strongly depend on assumptions about transformer sizing



Generalization # 1:

Voltage excursions and peak loading more strongly influenced by location than feeder type.

Generalization # 2:

Voltage regulator operations and % change in losses more strongly influenced by feeder type than location.

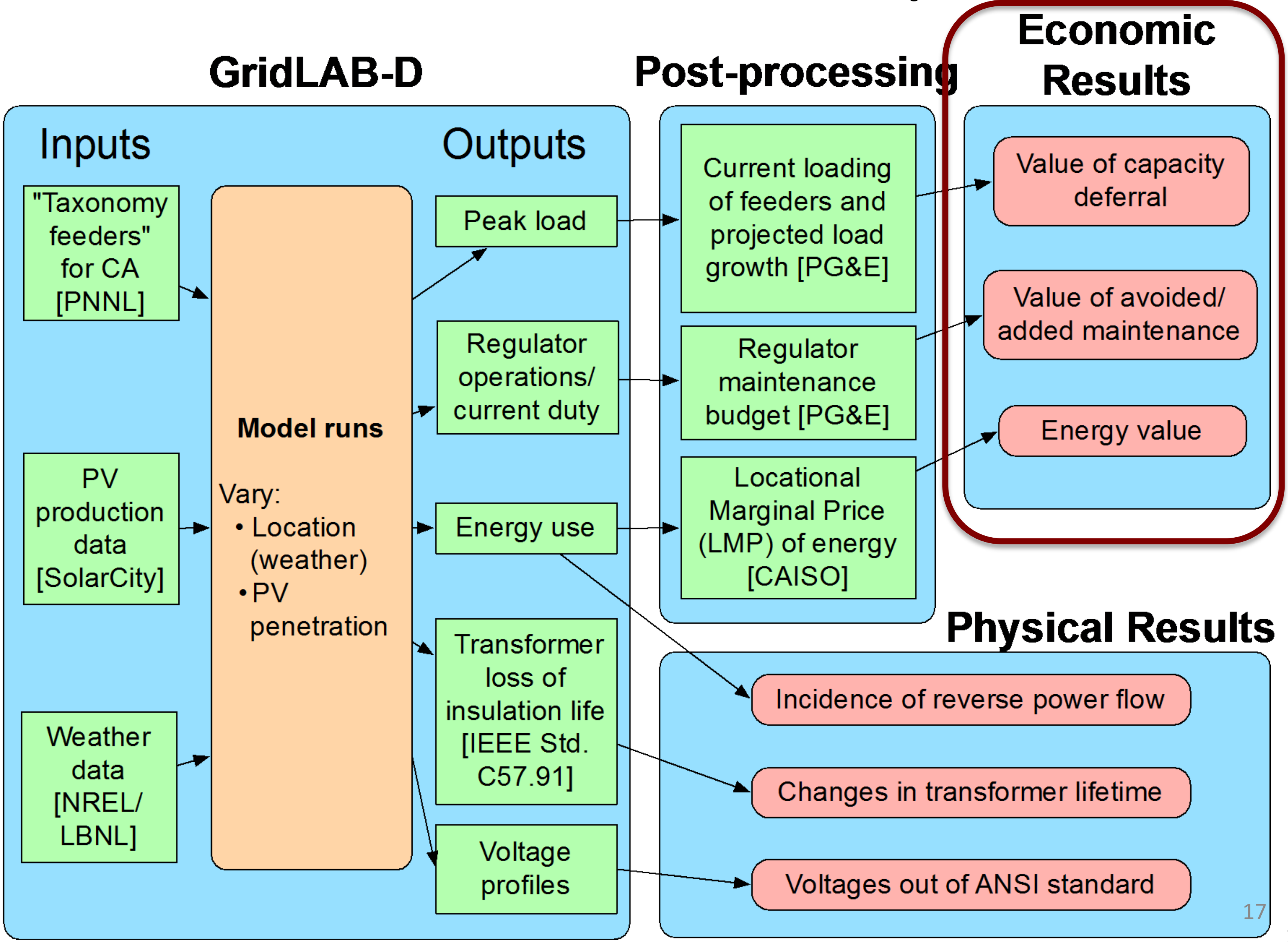
Generalization # 3:

Though impacts (positive and negative) are non-negligible, in this set of feeders and locations they are generally small

Additional Areas to Investigate

- Will location-driven results have less diversity if loading is defined as
  - % of max load at solar noon?
  - % energy delivered versus demand?
- Impact of spatially concentrated loading
- Causes of differing voltage regulator impacts

Part 2: Economic Impacts



Energy Value

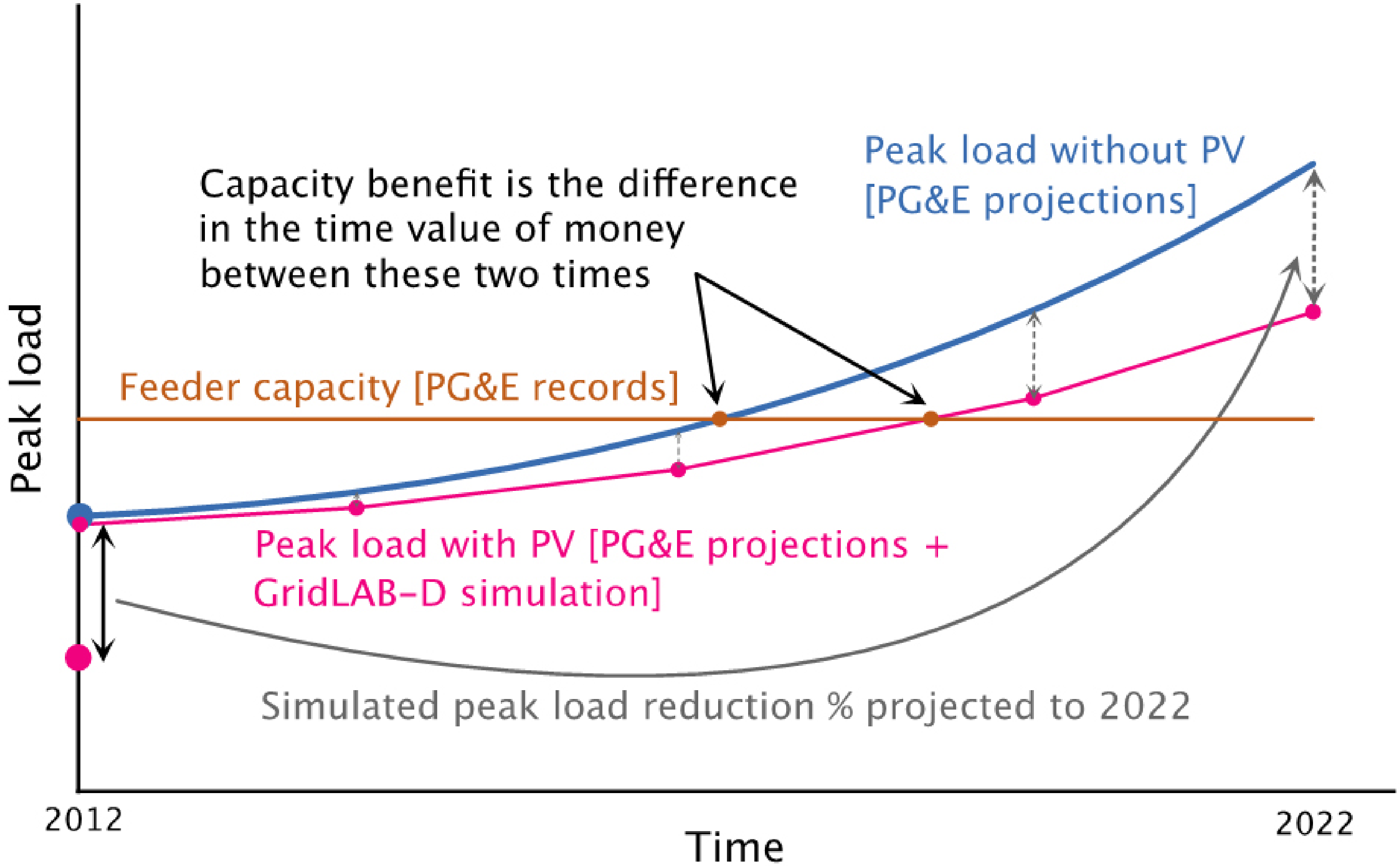
$$\frac{\text{cost of energy at substation, 0\% penetration} - \text{cost of energy at substation, X\% penetration}}{\text{PV production at X\% penetration}}$$

- Captures loss reduction and PV generation
- Energy prices from CAISO day ahead LMP data
  - Assume LMP independent of PV penetration
- Result: 3.50¢/kWh
- Reference: average LMP was 2.97¢/kWh in study period

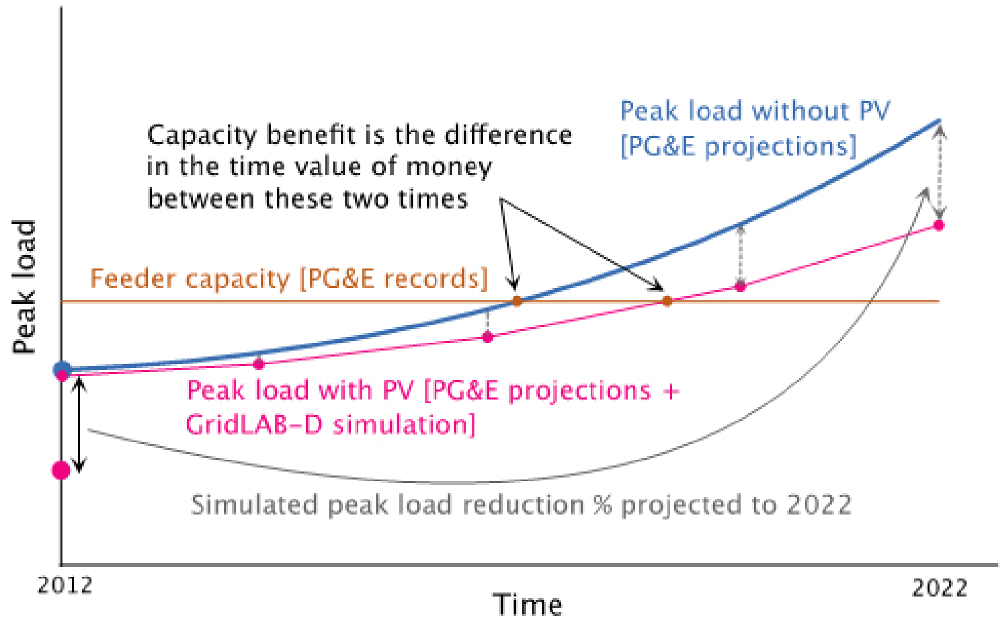
Distribution Capacity: Data, Assumptions

- For all ~3,000 feeders in PG&E (subject to NDA)
  - Peak MW demand and 5 year forecasted growth
  - Peak MW capacity
  - We dropped feeders
    - at or below 4.16 kV (2.4% of total capacity),
    - with 10% or more PV penetration (7.6% of tot. capacity)
    - already loaded over rated capacity (1.7% of total)
- PG&E distribution expenditures (major work category 06 and 46) for 2012-2016
  - In consultation with PG&E, 83-93 percent of MWC 06 and 46 considered sensitive to peak loading, depending on year
- PG&E weighted cost of capital = 7.6%, escalation / inflation = 2.5%

Capacity Deferral – Time Value of Money



Capacity Deferral – Time Value of Money

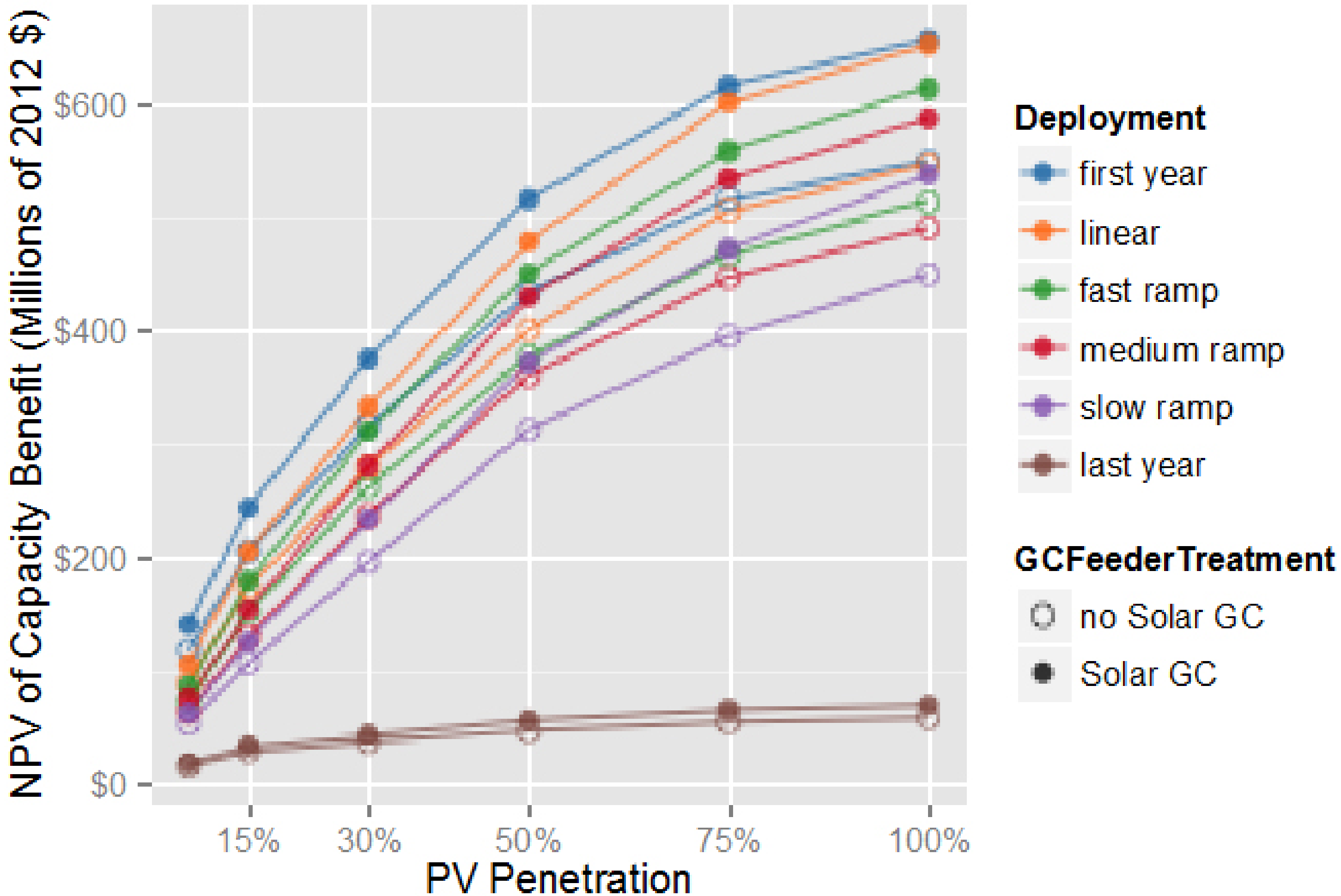


$$\text{savings ratio per project} = \frac{(\text{present value of original project}) - (\text{present value of deferred project})}{\text{present value of original project}}$$

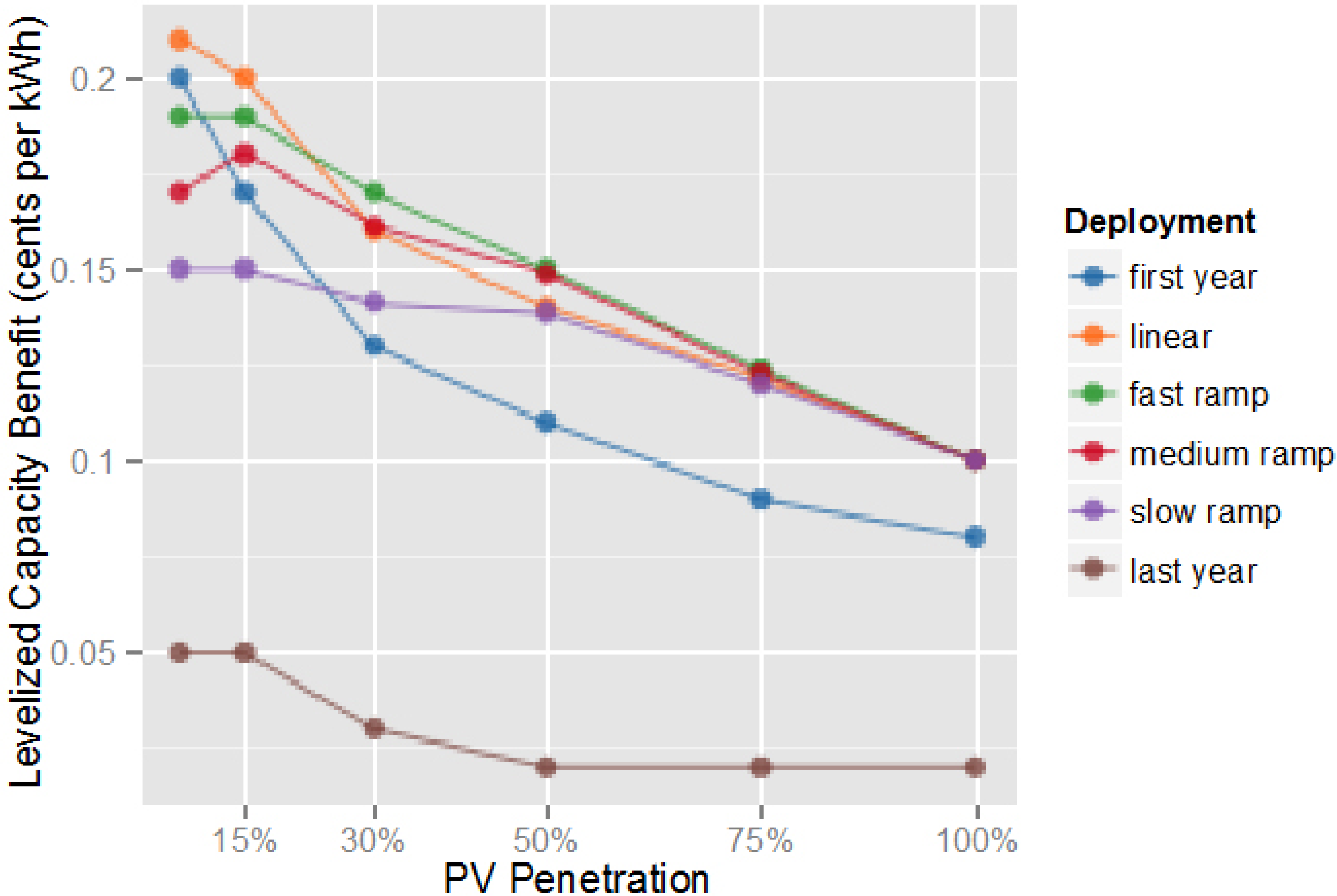
$$\text{Net present value of deferral} = \left(\text{average savings ratio}\right) \times \text{peak-load sensitive PG\&E distribution budget}$$

$$\text{Energy-levelized capacity benefit} = \frac{\text{net present value of deferral}}{\text{discounted energy produced}}$$

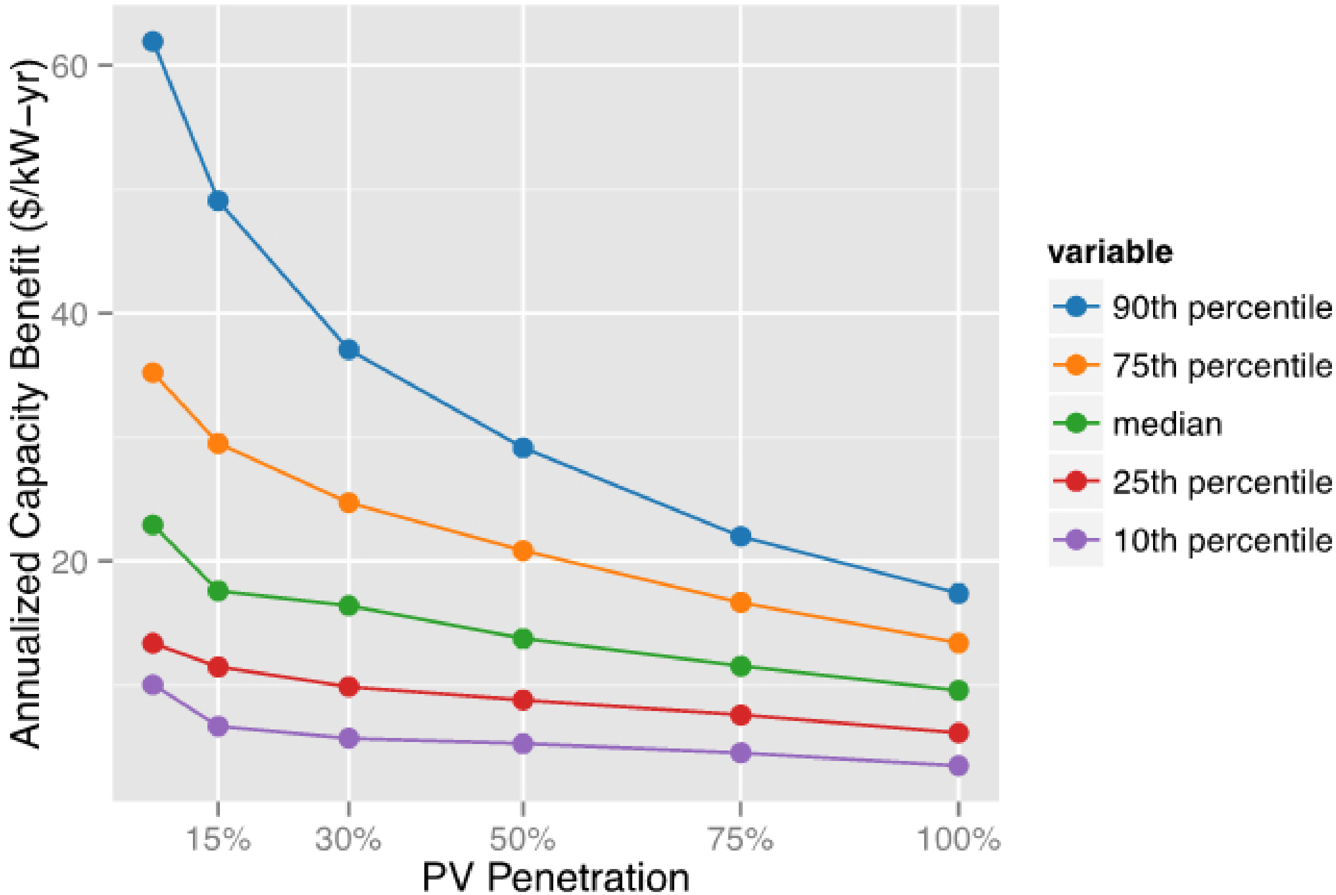
Total Capacity Benefit



Energy-Levelized Capacity Benefit



Distribution Capacity Benefit per kW of PV Capacity



Note: percentile is among those feeders that would have had projects in the study period (approximately 10 percent of total).

Other Economic Results

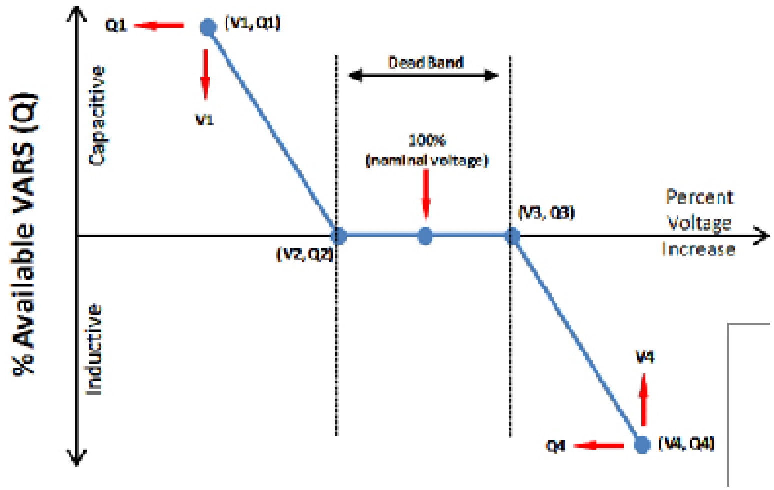
- Discount rate matters for capacity value
  - Increasing WACC to 10% roughly halves cap. value, decreasing to 5% roughly doubles cap. value.
- Voltage regulator maintenance costs likely small
  - Increased maintenance costs across all PG&E would be $100k-$400k/year at 100 percent penetration
    - Assuming voltage regulator maintenance scales linearly with voltage regulator operation
  - Contrast to capacity value, which is tens of millions per year

Key Economic Takeaways

1. Capacity deferral benefits are *very* heterogeneous, but:
   – Could be as large as avoided energy benefits; in general will be much smaller
   – Could approach the size of possible retail fixed charges, but in general will be much smaller
2. Economic costs to manage voltage problems appear to be very small across utility footprint
   – But matters on a few individual feeders
3. Costs at even higher penetrations could become significant – further study needed.

Part 3: Smart Inverter VVO

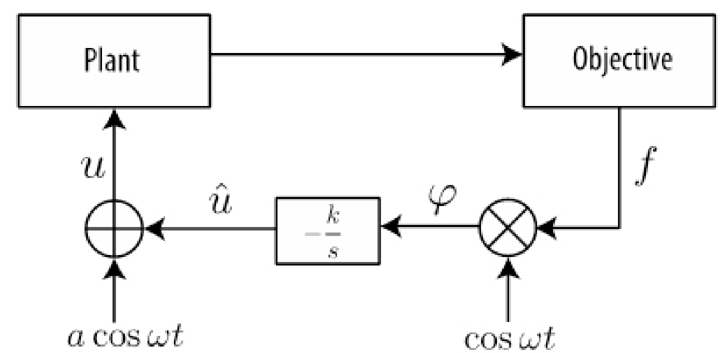
- Inverters can regulate voltage and reduce resistive losses by
  - injecting reactive power to raise local voltage or
  - absorbing reactive power to reduce local voltage
- Activity in this space:
  - Rule-based strategies, such as proposed IEEE 1547
    - Suboptimal, only regulates local voltage.
  - Model-based optimization strategies
    - Require exact model and measurements of all real and reactive power injections on feeder



Source: Aminul Huque, PV Distribution Systems Modeling Workshop (2014)

An Alternative Approach?

- Extremum-seeking (ES) control
  - Non-model based
  - Provided certain conditions are met, can optimize system
- Modulation signal (probing signal) is injected into plant dynamics: $u = \hat{u} + a \cos \omega t$
  - If separate controllers probe at different frequencies, they will not interfere
- Excited plant explores the local objective function
- Objective function output is demodulated
- Demodulated output passes through an integrator

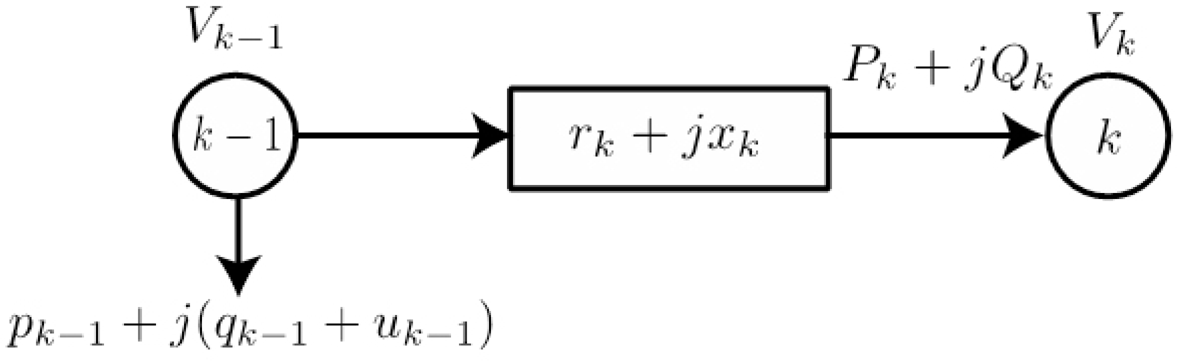


ES Applied to Volt VAR Optimization (VVO): Basic Approach

Control: Inject reactive power at different nodes on a feeder (multiple controllers)

Sensor: Measure real power demanded at feeder head, broadcast to inverters

Inverter-level objective: Minimize feeder head real power



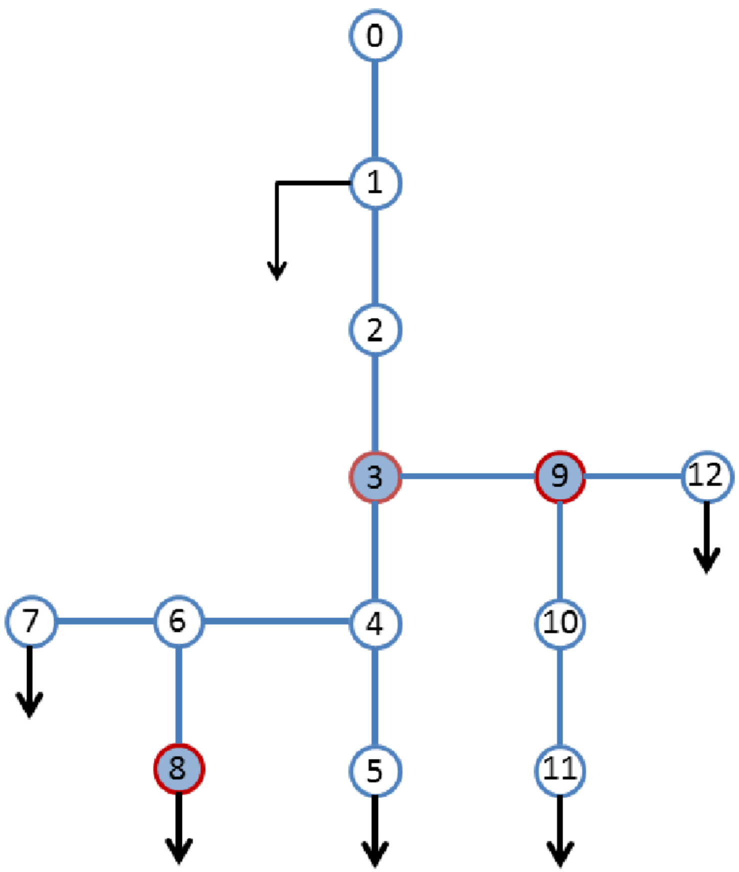
ES Applied to VVO: Central Questions

- Does this formulation satisfy the assumptions for ES to work?
  - Specifically, is feeder head real power *convex* w.r.t. reactive power at any point in the system?
- What happens to voltage magnitudes in this setting?
- Will it work in simulation?
- What is the best probing frequency to use?
- Will it work in practice?

Analytical Results

1. Real power at the feeder head is convex with respect to reactive power injection anywhere on the feeder
   – Statement requires that reverse power flow does not exceed the rating of each line
   – This result guarantees each controller will identify a setting that minimizes real power at feeder head
2. Voltage magnitudes will always move *closer* to the substation feeder head as a consequence of this control action
   – Guarantees that control action will not create voltage problems

Simulation Results



- Model from Kersting, *Distribution system modeling and analysis* (2012).
- Smart inverters at nodes 3, 8, and 9
  - Probing frequencies: 0.01-0.03 Hz
  - Inverter kVA ratings:
  - For now assume real power from PV does not limit reactive power injection
- Loads at nodes 1, 5, 7, 8, 11, and 12.
  - Publicly available 30 minute demand information (kW) from PG&E
  - Simulations with faster (1 minute data) also work (for those data we run controllers at approx 5-15 Hz)
  - We are in need of much faster data!

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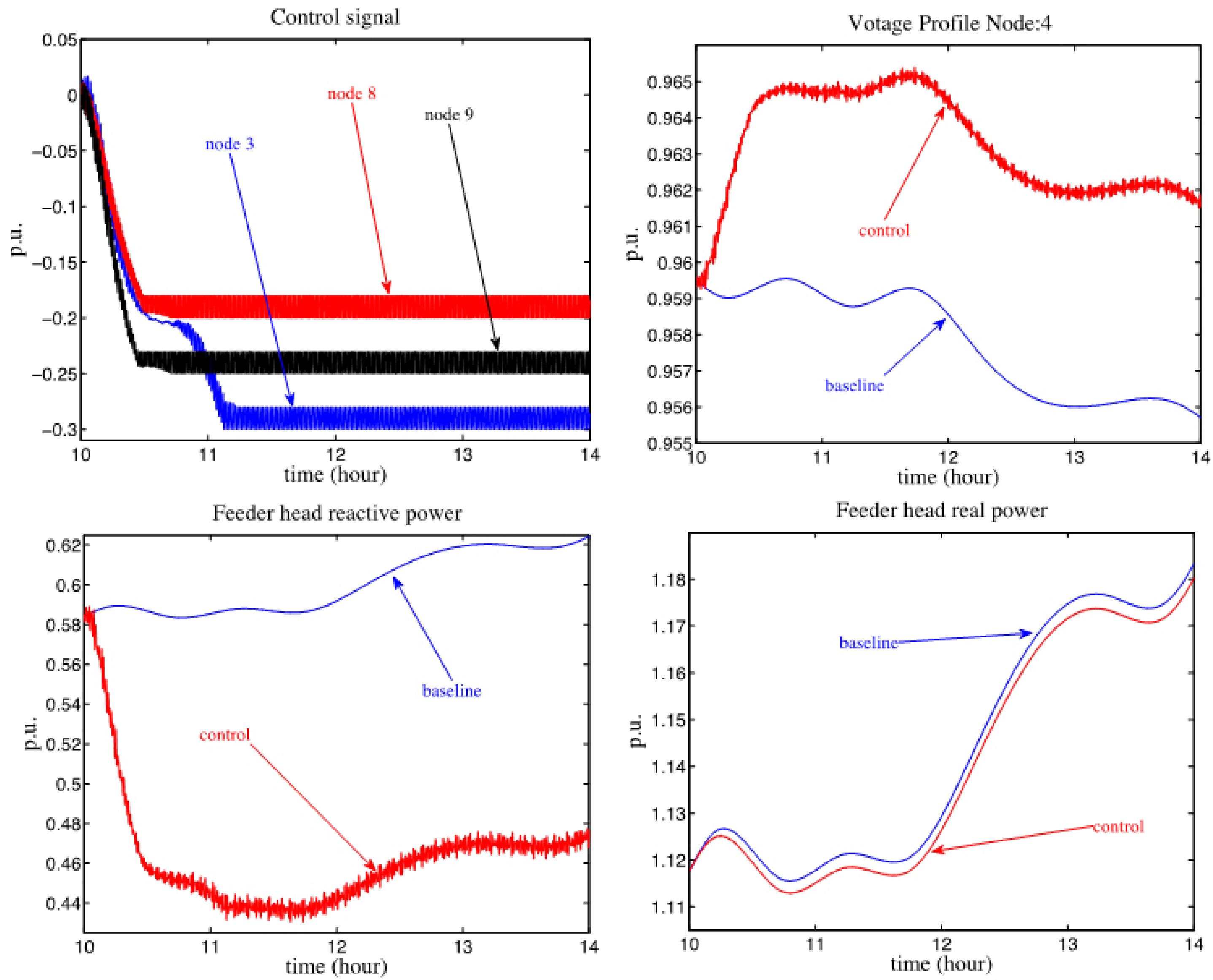
Simulation Results



ES Applied to VVO: Central Questions

- Does this formulation satisfy ES assumptions?
  – Yes, feeder head real power is convex in a wide range of power flow conditions
- What happens to voltage magnitudes?
  – They are improved
- Will it work in simulation?
  – Yes, so far
- What is the best probing frequency to use?
  – Need substn telemetry data to answer question
- Will it work in practice?
  – We are in search of a testbed….

ES Control: Interpretation and Future Work

Summary and interpretation

- Off-the-shelf *optimal* control, little to no tuning required in field
- One global measurement required, all other information local
- Interoperable – provided manufacturers have process for ensuring probing frequencies don't overlap

Future work:

- Inclusion of local or global voltage magnitude measurements in objective function

Summary

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Thank you

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